



## NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

### **August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts February 10, 2004**

#### **Preamble**

*The Board of Trustees recognizes the paramount importance of a reliable bulk electric system in North America. In consideration of the findings of the investigation into the August 14, 2003 blackout, NERC must take firm and immediate actions to increase public confidence that the reliability of the North American bulk electric system is being protected.*

*A key finding of the blackout investigators is that violations of existing NERC reliability standards contributed directly to the blackout. Pending enactment of federal reliability legislation creating a framework for enforcement of mandatory reliability standards, and with the encouragement of the Stakeholders Committee, the board is determined to obtain full compliance with all existing and future reliability standards and intends to use all legitimate means available to achieve that end. The board therefore resolves to:*

- *Receive specific information on all violations of NERC standards, including the identities of the parties involved;*
- *Take firm actions to improve compliance with NERC reliability standards;*
- *Provide greater transparency to violations of standards, while respecting the confidential nature of some information and the need for a fair and deliberate due process; and*
- *Inform and work closely with the Federal Energy Regulatory Commission and other applicable federal, state, and provincial regulatory authorities in the United States, Canada, and Mexico as needed to ensure public interests are met with respect to compliance with reliability standards.*

*The board expresses its appreciation to the blackout investigators and the Steering Group for their objective and thorough work in preparing a report of recommended NERC actions. With a few clarifications, the board approves the report and directs implementation of the recommended actions. The board holds the assigned committees and organizations accountable to report to the board the progress in completing the recommended actions, and intends itself to publicly report those results. The board recognizes the possibility that this action plan may have to be adapted as additional analysis is completed, but stresses the need to move forward immediately with the actions as stated.*

*Furthermore, the board directs management to immediately advise the board of any significant violations of NERC reliability standards, including details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Management shall supply to the board in advance of board meetings a detailed report of all violations of reliability standards.*

*Finally, the board resolves to form a task force to develop guidelines for the board to consider with regard to the confidentiality of compliance information and disclosure of such information to regulatory authorities and the public.*

## **Overview of Investigation Conclusions**

The North American Electric Reliability Council (NERC) has conducted a comprehensive investigation of the August 14, 2003 blackout. The results of NERC's investigation contributed significantly to the U.S./Canada Power System Outage Task Force's November 19, 2003 Interim Report identifying the root causes of the outage and the sequence of events leading to and during the cascading failure. NERC fully concurs with the conclusions of the Interim Report and continues to provide its support to the Task Force through ongoing technical analysis of the outage. Although an understanding of what happened and why has been resolved for most aspects of the outage, detailed analysis continues in several areas, notably dynamic simulations of the transient phases of the cascade and a final verification of the full scope of all violations of NERC and regional reliability standards that occurred leading to the outage.

From its investigation of the August 14 blackout, NERC concludes that:

- Several entities violated NERC operating policies and planning standards, and those violations contributed directly to the start of the cascading blackout.
- The existing process for monitoring and assuring compliance with NERC and regional reliability standards was shown to be inadequate to identify and resolve specific compliance violations before those violations led to a cascading blackout.
- Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system.
- Problems identified in studies of prior large-scale blackouts were repeated, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions.
- In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking with actual system data and field testing.
- Planning studies, design assumptions, and facilities ratings were not consistently shared and were not subject to adequate peer review among operating entities and regions.
- Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system.

## **Overview of Recommendations**

The Board of Trustees approves the NERC Steering Group recommendations to address these shortcomings. The recommendations fall into three categories.

**Actions to Remedy Specific Deficiencies:** Specific actions directed to First Energy (FE), the Midwest Independent System Operator (MISO), and the PJM Interconnection, LLC (PJM) to correct the deficiencies that led to the blackout.

1. Correct the Direct Causes of the August 14, 2003 Blackout.

**Strategic Initiatives:** Strategic initiatives by NERC and the regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14, and other significant power system events.

2. Strengthen the NERC Compliance Enforcement Program.
3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.
4. Evaluate Vegetation Management Procedures and Results.
5. Establish a Program to Track Implementation of Recommendations.

**Technical Initiatives:** Technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

6. Improve Operator and Reliability Coordinator Training
7. Evaluate Reactive Power and Voltage Control Practices.
8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.
10. Establish Guidelines for Real-Time Operating Tools.
11. Evaluate Lessons Learned During System Restoration.
12. Install Additional Time-Synchronized Recording Devices as Needed.
13. Reevaluate System Design, Planning and Operating Criteria.
14. Improve System Modeling Data and Data Exchange Practices.

## **Market Impacts**

Many of the recommendations in this report have implications for electricity markets and market participants, particularly those requiring reevaluation or clarification of NERC and regional standards, policies and criteria. Implicit in these recommendations is that the NERC board charges the Market Committee with assisting in the implementation of the recommendations and interfacing with the North American Energy Standards Board with respect to any necessary business practices.

## **Recommendation to Remedy Specific Deficiencies**

### **Recommendation 1. Correct the Direct Causes of the August 14, 2003 Blackout.**

NERC's technical analysis of the August 14 blackout leads it to fully concur with the Task Force Interim Report regarding the direct causes of the blackout. The report stated that the principal causes of the blackout were that FE did not maintain situational awareness of conditions on its power system and did not adequately manage tree growth in its transmission rights-of-way. Contributing factors included ineffective diagnostic support provided by MISO as the reliability coordinator for FE and ineffective communications between MISO and PJM.

NERC will take immediate and firm actions to ensure that the same deficiencies that were directly causal to the August 14 blackout are corrected. These steps are necessary to assure electricity customers, regulators and others with an interest in the reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the specific causes of the August 14 blackout have been identified and fixed.

**Recommendation 1a: FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC board no later than June 30, 2004, that these specified actions have been completed. Furthermore, each organization shall present its detailed plan for completing these actions to the NERC committees for technical review on March 23-24, 2004, and to the NERC board for approval no later than April 2, 2004.**

**Recommendation 1b: The NERC Technical Steering Committee shall immediately assign a team of experts to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.**

## **Strategic Initiatives to Assure Compliance with Reliability Standards and to Track Recommendations**

### **Recommendation 2. Strengthen the NERC Compliance Enforcement Program.**

NERC's analysis of the actions and events leading to the August 14 blackout leads it to conclude that several violations of NERC operating policies contributed directly to an uncontrolled, cascading outage on the Eastern Interconnection. NERC continues to investigate additional violations of NERC and regional reliability standards and expects to issue a final report of those violations in March 2004.

In the absence of enabling legislation in the United States and complementary actions in Canada and Mexico to authorize the creation of an electric reliability organization, NERC lacks legally sanctioned authority to enforce compliance with its reliability rules. However, the August 14 blackout is a clear signal that voluntary compliance with reliability rules is no longer adequate. NERC and the regional reliability councils must assume firm authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take immediate and effective actions to ensure that such violations are corrected.

Violations of NERC standards identified in the November 19, 2003 Interim Report:

1. Following the outage of the Chamberlin-Harding 345 kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes (violation of NERC Operating Policy 2).
2. FE did not notify other systems of an impending system emergency (violation of NERC Operating Policy 5).
3. FE's analysis tools were not used to effectively assess system conditions (violation of NERC Operating Policy 5).
4. FE operator training was inadequate for maintaining reliable conditions (violation of NERC Operating Policy 8).
5. MISO did not notify other reliability coordinators of potential problems (violation of NERC Operating Policy 9).

**Recommendation 2a: Each regional reliability council shall report to the NERC Compliance Enforcement Program within one month of occurrence all significant<sup>1</sup> violations of NERC operating policies and planning standards and regional standards, whether verified or still under investigation. Such reports shall confidentially note details regarding the nature and potential reliability impacts of the alleged violations and the identity of parties involved. Additionally, each regional reliability council shall report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability council standards.**

**Recommendation 2b: Being presented with the results of the investigation of any significant violation, and with due consideration of the surrounding facts and circumstances, the NERC board shall require an offending organization to correct the violation within a specified time. If the board determines that an offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the board will seek to remedy the violation by requesting assistance of the appropriate regulatory authorities in the United States, Canada, and Mexico.**

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<sup>1</sup> Although all violations are important, a significant violation is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems. By contrast, a violation of a reporting or administrative requirement would not by itself generally be considered a significant violation.

**Recommendation 2c: The Planning and Operating Committees, working in conjunction with the Compliance Enforcement Program, shall review and update existing approved and draft compliance templates applicable to current NERC operating policies and planning standards; and submit any revisions or new templates to the board for approval no later than March 31, 2004. To expedite this task, the NERC President shall immediately form a Compliance Template Task Force comprised of representatives of each committee. The Compliance Enforcement Program shall issue the board-approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.**

This effort will make maximum use of existing approved and draft compliance templates in order to meet the aggressive schedule. The templates are intended to include all existing NERC operating policies and planning standards but can be adapted going forward to incorporate new reliability standards as they are adopted by the NERC board for implementation in the future.

When the investigation team's final report on the August 14 violations of NERC and regional standards is available in March, it will be important to assess and understand the lapses that allowed violations to go unreported until a large-scale blackout occurred.

**Recommendation 2d: The NERC Compliance Enforcement Program and ECAR shall, within three months of the issuance of the final report from the Compliance and Standards investigation team, evaluate the identified violations of NERC and regional standards, as compared to previous compliance reviews and audits for the applicable entities, and develop recommendations to improve the compliance process.**

### **Recommendation 3. Initiate Control Area and Reliability Coordinator Reliability Readiness Audits.**

In conducting its investigation, NERC found that deficiencies in control area and reliability coordinator capabilities to perform assigned reliability functions contributed to the August 14 blackout. In addition to specific violations of NERC and regional standards, some reliability coordinators and control areas were deficient in the performance of their reliability functions and did not achieve a level of performance that would be considered acceptable practice in areas such as operating tools, communications, and training. In a number of cases there was a lack of clarity in the NERC policies with regard to what is expected of a reliability coordinator or control area. Although the deficiencies in the NERC policies must be addressed (see Recommendation 9), it is equally important to recognize that standards cannot prescribe all aspects of reliable operation and that minimum standards present a threshold, not a target for performance. Reliability coordinators and control areas must perform well, particularly under emergency conditions, and at all times strive for excellence in their assigned reliability functions and responsibilities.

**Recommendation 3a: The NERC Compliance Enforcement Program and the regional reliability councils shall jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14 blackout investigation. Audits of all control areas and reliability coordinators shall be completed within three years and continue in a three-year cycle. The 20 highest priority audits, as determined by the Compliance Enforcement Program, will be completed by June 30, 2004.**

**Recommendation 3b: NERC will establish a set of baseline audit criteria to which regional criteria may be added. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.**

**Recommendation 3c: The reliability regions, with the oversight and direct participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other members of the audit teams.**

#### **Recommendation 4. Evaluate Vegetation Management Procedures and Results.**

Ineffective vegetation management was a major cause of the August 14 blackout and also contributed to other historical large-scale blackouts, such as on July 2-3, 1996 in the west. Maintaining transmission line rights-of-way (ROW), including maintaining safe clearances of energized lines from vegetation, under-build, and other obstructions<sup>2</sup> incurs a substantial ongoing cost in many areas of North America. However, it is an important investment for assuring a reliable electric system.

NERC does not presently have standards for ROW maintenance. Standards on vegetation management are particularly challenging given the great diversity of vegetation and growth patterns across North America. However, NERC's standards do require that line ratings are calculated so as to maintain safe clearances from all obstructions. Furthermore, in the United States, the National Electrical Safety Code (NESC) Rules 232, 233, and 234 detail the minimum vertical and horizontal safety clearances of overhead conductors from grounded objects and various types of obstructions. NESC Rule 218 addresses tree clearances by simply stating, "Trees that may interfere with ungrounded supply conductors should be trimmed or removed." Several states have adopted their own electrical safety codes and similar codes apply in Canada.

Recognizing that ROW maintenance requirements vary substantially depending on local conditions, NERC will focus attention initially on measuring performance as indicated by the number of high voltage line trips caused by vegetation rather than immediately move toward developing standards for

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<sup>2</sup> Vegetation, such as the trees that caused the initial line trips in FE that led to the August 14, 2003 outage is not the only type of obstruction that can breach the safe clearance distances from energized lines. Other examples include under-build of telephone and cable TV lines, train crossings, and even nests of certain large bird species.

ROW maintenance. This approach has worked well in the Western Electricity Coordinating Council (WECC) since being instituted after the 1996 outages.

**Recommendation 4a: NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system<sup>3</sup> transmission line trips resulting from vegetation contact<sup>4</sup>. The program will use the successful WECC vegetation monitoring program as a model.**

**Recommendation 4b: Beginning with an effective date of January 1, 2004, each transmission operator will submit an annual report of all vegetation-related high voltage line trips to its respective reliability region. Each region shall assemble a detailed annual report of vegetation-related line trips in the region to NERC no later than March 31 for the preceding year, with the first reporting to be completed by March 2005 for calendar year 2004.**

Vegetation management practices, including inspection and trimming requirements, can vary significantly with geography. Additionally, some entities use advanced techniques such as planting beneficial species or applying growth retardants. Nonetheless, the events of August 14 and prior outages point to the need for independent verification that viable programs exist for ROW maintenance and that the programs are being followed.

**Recommendation 4c: Each bulk electric transmission owner shall make its vegetation management procedure, and documentation of work completed, available for review and verification upon request by the applicable regional reliability council, NERC, or applicable federal, state or provincial regulatory agency.**

Should this approach of monitoring vegetation-related line outages and procedures prove ineffective in reducing the number of vegetation-related line outages, NERC will consider the development of minimum line clearance standards to assure reliability.

#### **Recommendation 5. Establish a Program to Track Implementation of Recommendations.**

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, including:

- Conductors contacting trees
- Ineffective visualization of power system conditions and lack of situational awareness
- Ineffective communications
- Lack of training in recognizing and responding to emergencies
- Insufficient static and dynamic reactive power supply
- Need to improve relay protection schemes and coordination

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<sup>3</sup> All transmission lines operating at 230 kV and higher voltage, and any other lower voltage lines designated by the regional reliability council to be critical to the reliability of the bulk electric system, shall be included in the program.

<sup>4</sup> A line trip includes a momentary opening and reclosing of the line, a lock out, or a combination. For reporting purposes, all vegetation-related openings of a line occurring within one 24-hour period should be considered one event. Trips known to be caused by severe weather or other natural disaster such as earthquake are excluded. Contact with vegetation includes both physical contact and arcing due to insufficient clearance.

It is important that recommendations resulting from system outages be adopted consistently by all regions and operating entities, not just those directly affected by a particular outage. Several lessons learned prior to August 14, if heeded, could have prevented the outage. WECC and NPCC, for example, have programs that could be used as models for tracking completion of recommendations. NERC and some regions have not adequately tracked completion of recommendations from prior events to ensure they were consistently implemented.

Recommendation 5a: NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff shall report both NERC activities and a summary of regional activities to the board.

Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also adopt a process for continuous learning and improvement by seeking continuous feedback on reliability performance trends, not rely mainly on learning from and reacting to catastrophic failures.

**Recommendation 5b: NERC shall by January 1, 2005 establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance.**

Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14 blackout investigation. This function would incorporate the current Disturbance Analysis Working Group and expand that work to provide more proactive feedback to the NERC board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the board of reliability trends. This function could develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared between NERC and the regional reliability councils for use as needed, with NERC and regional investigation roles clearly defined in advance.

## **Technical Initiatives to Minimize the Likelihood and Impacts of Possible Future Cascading Outages**

### **Recommendation 6. Improve Operator and Reliability Coordinator Training.**

NERC found during its investigation that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills for training and verifying the capabilities of operating personnel. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency when operator intervention was still possible prior to the high speed portion of the sequence of events.

**Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations<sup>5</sup>, for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits.**

NERC has published Continuing Education Criteria specifying appropriate qualifications for continuing education providers and training activities.

In the longer term, the NERC Personnel Certification Governance Committee (PCGC), which is independent of the NERC board, should explore expanding the certification requirements of system operating personnel to include additional measures of competency in recognizing and responding to system emergencies. The current NERC certification examination is a written test of the NERC Operating Manual and other references relating to operator job duties, and is not by itself intended to be a complete demonstration of competency to handle system emergencies.

### **Recommendation 7. Evaluate Reactive Power and Voltage Control Practices.**

The August 14 blackout investigation identified inconsistent practices in northeastern Ohio with regard to the setting and coordination of voltage limits and insufficient reactive power supply. Although the deficiency of reactive power supply in northeastern Ohio did not directly cause the blackout, it was a contributing factor and was a significant violation of existing reliability standards.

In particular, there appear to have been violations of NERC Planning Standard I.D.S1 requiring static and dynamic reactive power resources to meet the performance criteria specified in Table I of

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<sup>5</sup> The term “realistic simulations” includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency. Although a full replica training simulator is one approach, lower cost alternatives such as PC-based simulators, tabletop drills, and simulated communications can be effective training aids if used properly.

Planning Standard I.A on Transmission Systems. Planning Standard II.B.S1 requires each regional reliability council to establish procedures for generating equipment data verification and testing, including reactive power capability. Planning Standard III.C.S1 requires that all synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. S2 of this standard also requires that generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units.

On one hand, the unsafe conditions on August 14 with respect to voltage in northeastern Ohio can be said to have resulted from violations of NERC planning criteria for reactive power and voltage control, and those violations should have been identified through the NERC and ECAR compliance monitoring programs (addressed by Recommendation 2). On the other hand, investigators believe these deficiencies are also symptomatic of a systematic breakdown of the reliability studies and practices in FE and the ECAR region that allowed unsafe voltage criteria to be set and used in study models and operations. There were also issues identified with reactive characteristics of loads, as addressed in Recommendation 14.

**Recommendation 7a: The Planning Committee shall reevaluate within one year the effectiveness of the existing reactive power and voltage control standards and how they are being implemented in practice in the ten NERC regions. Based on this evaluation, the Planning Committee shall recommend revisions to standards or process improvements to ensure voltage control and stability issues are adequately addressed.**

**Recommendation 7b: ECAR shall no later than June 30, 2004 review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC board.**

**Recommendation 8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.**

The importance of automatic control and protection systems in preventing, slowing, or mitigating the impact of a large-scale outage cannot be stressed enough. To underscore this point, following the trip of the Sammis-Star line at 4:06, the cascading failure into parts of eight states and two provinces, including the trip of over 531 generating units and over 400 transmission lines, was completed in the next eight minutes. Most of the event sequence, in fact, occurred in the final 12 seconds of the cascade. Likewise, the July 2, 1996 failure took less than 30 seconds and the August 10, 1996 failure took only 5 minutes. It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. The NERC investigators believe that two measures would have been crucial in slowing or stopping the uncontrolled cascade on August 14:

- Better application of zone 3 impedance relays on high voltage transmission lines
- Selective use of under-voltage load shedding.

First, beginning with the Sammis-Star line trip, most of the remaining line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload (a combination of high amperes and low voltage) on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays, and are not intentionally set to operate on a line overload. However, under extreme conditions of low voltages and large power swings as seen on August 14, zone 3 relays can operate for overload conditions and propagate the outage to a wider area by essentially causing the system to “break up”. Many of the zone 3 relays that operated during the August 14 cascading outage were not set with adequate margins above their emergency thermal ratings. For the short times involved, thermal heating is not a problem and the lines should not be tripped for overloads. Instead, power system protection devices should be set to address the specific condition of concern, such as a fault, out-of-step condition, etc., and should not compromise a power system’s inherent physical capability to slow down or stop a cascading event.

**Recommendation 8a:** All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions<sup>6</sup>. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

A second key finding with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area on August 14, there is a high probability the outage could have been limited to that area.

**Recommendation 8b:** Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

The NERC investigation of the August 14 blackout has identified additional transmission and generation control and protection issues requiring further analysis. One concern is that generating unit control and protection schemes need to consider the full range of possible extreme system conditions, such as the low voltages and low and high frequencies experienced on August 14. The team also noted that improvements may be needed in under-frequency load shedding and its coordination with generator under-and over-frequency protection and controls.

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<sup>6</sup> The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

**Recommendation 8c: The Planning Committee shall evaluate Planning Standard III – System Protection and Control and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascading failure. The board directs the Planning Committee to evaluate the lessons from August 14 regarding relay protection design and application and offer additional recommendations for improvement.**

**Recommendation 9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities.**

Ambiguities in the NERC operating policies may have allowed entities involved in the August 14 blackout to make different interpretations regarding the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas. Characteristics and capabilities necessary to enable prompt recognition and effective response to system emergencies must be specified.

The lack of timely and accurate outage information resulted in degraded performance of state estimator and reliability assessment functions on August 14. There is a need to review options for sharing of outage information in the operating time horizon (e.g. 15 minutes or less), so as to ensure the accurate and timely sharing of outage data necessary to support real-time operating tools such as state estimators, real-time contingency analysis, and other system monitoring tools.

On August 14, reliability coordinator and control area communications regarding conditions in northeastern Ohio were ineffective, and in some cases confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during emergencies, is essential to reliability. Alternatives should be considered to one-on-one phone calls during an emergency to ensure all parties are getting timely and accurate information with a minimum number of calls.

NERC operating policies do not adequately specify critical facilities, leaving ambiguity regarding which facilities must be monitored by reliability coordinators. Nor do the policies adequately define criteria for declaring transmission system emergencies. Operating policies should also clearly specify that curtailing interchange transactions through the NERC Transmission Loading Relief (TLR) Procedure is not intended as a method for restoring the system from an actual Operating Security Limit violation to a secure operating state.

**Recommendation 9: The Operating Committee shall complete the following by June 30, 2004:**

- Evaluate and revise the operating policies and procedures, or provide interpretations, to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined.
- Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies.
- Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.

## **Recommendation 10. Establish Guidelines for Real-Time Operating Tools.**

The August 14 blackout was caused by a lack of situational awareness that was in turn the result of inadequate reliability tools and backup capabilities. Additionally, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure of its state estimator to work effectively on August 14 contributed to the lack of situational awareness.

**Recommendation 10: The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.**

This evaluation should include consideration of the following:

- Modeling requirements, such as model size and fidelity, real and reactive load modeling, sensitivity analyses, accuracy analyses, validation, measurement, observability, update procedures, and procedures for the timely exchange of modeling data.
- State estimation requirements, such as periodicity of execution, monitoring external facilities, solution quality, topology error and measurement error detection, failure rates including times between failures, presentation of solution results including alarms, and troubleshooting procedures.
- Real-time contingency analysis requirements, such as contingency definition, periodicity of execution, monitoring external facilities, solution quality, post-contingency automatic actions, failure rates including mean/maximum times between failures, reporting of results, presentation of solution results including alarms, and troubleshooting procedures including procedures for investigating unsolvable contingencies.

## **Recommendation 11. Evaluate Lessons Learned During System Restoration.**

The efforts to restore the power system and customer service following the outage were effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery. Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to determine opportunities for improvement. Blackstart and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to apply actual events and experiences to learn to better prepare for system blackstart and restoration in the future. That opportunity should not be lost, despite the relative success of the restoration phase of the outage.

**Recommendation 11a: The Planning Committee, working in conjunction with the Operating Committee, NPCC, ECA, and PJM, shall evaluate the black start and system restoration performance following the outage of August 14, and within one year report to the NERC board the results of that evaluation with recommendations for improvement.**

**Recommendation 11b: All regional reliability councils shall, within six months of the Planning Committee report to the NERC board, reevaluate their procedures and plans to assure an effective blackstart and restoration capability within their region.**

**Recommendation 12. Install Additional Time-Synchronized Recording Devices as Needed.**

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.

NERC Planning Standard I.F – Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their Wide-Area Monitoring System (WAMS).

**Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.**

**Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders.**

**Recommendation 13. Reevaluate System Design, Planning and Operating Criteria.**

The investigation report noted that FE entered the day on August 14 with insufficient resources to stay within operating limits following a credible set of contingencies, such as the loss of the East Lake 5 unit and the Chamberlin-Harding line. NERC will conduct an evaluation of operations planning practices and criteria to ensure expected practices are sufficient and well understood. The review will reexamine fundamental operating criteria, such as n-1 and the 30-minute limit in preparing the system for a next contingency, and Table I Category C.3 of the NERC planning standards. Operations planning and operating criteria will be identified that are sufficient to ensure the system is in a known and reliable condition at all times, and that positive controls, whether

manual or automatic, are available and appropriately located at all times to return the Interconnection to a secure condition. Daily operations planning, and subsequent real time operations planning will identify available system reserves to meet operating criteria.

**Recommendation 13a: The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions in a report to the board within one year.**

Prior studies in the ECAR region did not adequately define the system conditions that were observed on August 14. Severe contingency criteria were not adequate to address the events of August 14 that led to the uncontrolled cascade. Also, northeastern Ohio was found to have insufficient reactive support to serve its loads and meet import criteria. Instances were also noted in the FE system and ECAR area of different ratings being used for the same facility by planners and operators and among entities, making the models used for system planning and operation suspect. NERC and the regional reliability councils must take steps to assure facility ratings are being determined using consistent criteria and being effectively shared and reviewed among entities and among planners and operators.

**Recommendation 13b: ECAR shall no later than June 30, 2004 reevaluate its planning and study procedures and practices to ensure they are in compliance with NERC standards, ECAR Document No. 1, and other relevant criteria; and that ECAR and its members' studies are being implemented as required.**

**Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.**

Regional reliability councils may consider assembling a regional database that includes the ratings of all bulk electric system (100 kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis.

NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area.

**Recommendation 14. Improve System Modeling Data and Data Exchange Practices.**

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage

conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

**Recommendation 14: The regional reliability councils shall within one year establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.**

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, data was frequently not supplied. The reason often given was that the control area did not know the status or output of the generator at a given point in time. Another reason was the commercial sensitivity or confidentiality of such data.

## **Attachment A to Recommendation 1**

### **Corrective Actions to Be Taken by FirstEnergy, Midwest Independent System Operator and PJM Final – February 10, 2004**

This attachment identifies corrective actions to be completed by FE, MISO, and PJM no later than June 30, 2004, as referenced in NERC Recommendation 1. These actions are intended to assure peer operating systems and reliability coordinators, regulators, electricity customers, and the public that the specific deficiencies leading to the August 14, 2003 cascading outage have been resolved and will not be the cause of a similar outage in the near future.

#### **A. Corrective Actions to Be Completed by FirstEnergy**

FirstEnergy shall complete the following corrective actions by June 30, 2004. Unless otherwise stated, the requirements apply to FE's northern Ohio system and connected generators.

##### **1. Voltage Criteria and Reactive Resources**

- a. **Interim Voltage Criteria.** The investigation team found that FE was not operating on August 14 within NERC planning and operating criteria with respect to its voltage profile and reactive power supply margin in the Cleveland-Akron area. FE was also operating in apparent violation of its own historical planning and operating criteria that were developed and used by Centerior Energy Corporation (The Cleveland Electric Illuminating Company and the Toledo Edison Company) prior to 1998 to meet the relevant NERC and ECAR standards and criteria. FE's stated acceptable ranges for voltage are not compatible with neighboring systems or interconnected systems in general.

Until such time that the study of the northern Ohio system ordered by the Federal Energy Regulatory Commission (FERC) on December 23 is completed, and until FE is able to determine (in b. below) a current set of voltage and reactive requirements verified to be within NERC and ECAR criteria, FE shall immediately operate such that voltages at all 345 kV buses in the Cleveland-Akron area shall have a minimum voltage of .95 per unit following the simultaneous loss of the two largest generating units in that area.

- b. **Calculation of Minimum Bus Voltages and Reactive Reserves.** FE shall, consistent with or as part of the FERC-ordered study, determine the minimum location-specific voltages at all 345 kV and 138 kV buses and all generating stations within their control area (including merchant plants). FE shall determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1. Criteria and minimum voltage requirements

- must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.
- c. **Voltage Procedures.** FE shall determine voltage and reactive criteria and procedures to enable operators to understand and operate to these criteria.
  - d. **Study Results.** When the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcements, FE shall develop a plan for developing such reinforcements as soon as practical, and shall develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.
  - e. **Reactive Resources.** FE shall inspect all reactive resources, including generators, and assure that all are fully operational. FE shall verify that all installed capacitors have no blown fuses and that at least 98% of installed capacitors at 69 kV and higher are available and in service during the summer 2004.
  - f. **Communications.** FE shall communicate its voltage criteria and procedures, as described in the items above to MISO and FE's neighboring systems.

## 2. Operational Preparedness and Action Plan

FE's 2003 Summer Assessment was not considered to be sufficiently comprehensive to cover a wide range of known and expected system conditions, nor effective for the August 14 conditions based on the following:

- No voltage stability assessment was included to assess the Cleveland-Akron area which has a long-known history of potential voltage collapse, as indicated CEI studies prior to 1997, by non-convergence of powerflow studies in the 1998 analysis, and advice from AEP of potential voltage collapse prior to the onset of 2003 summer load period.
- Only single contingencies were tested for basically one set of 2003 study conditions. This does not comply with the study requirements of ECAR Document 1.
- Study conditions should have assumed a wider range of generation dispatch and import/export and inter-regional transfers. For example, imports from MECS (north-to-south transfers) are likely to be less stressful to the FE system than imports from AEP (south-to-north transfers). Sensitivity studies should have been conducted to assess the impact of each key parameter and derive the system operating limits accordingly based on the most limiting of transient stability, voltage stability and thermal capability.

- The 2003 study conditions are considered to be more onerous than those assumed in the 1998 study, since the former has Davis Besse (830 MW) as a scheduled outage. However, the 2003 study does not show any voltage instability problems as shown by the 1998 study.
- The 2003 study conditions are far less onerous than the actual August 14 conditions from the generation and transmission availability viewpoint. This is another indication that n-1 contingency assessment, based on one assumed system condition, is not sufficient to cover the variability of changing system conditions due to forced outages.

FE shall prepare and submit to ECAR, with a copy to NERC, an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and planning and operating criteria, including ECAR Document 1. The action plan shall include, but not be limited to the following:

- a. **2004 Summer Studies.** Complete a 2004 summer study to identify a comprehensive set of System Operating Limits (SOL) and Interconnection Reliability Limits (IRLs) based on the NERC Operating Limit Definition Task Force Report. Any inter-dependency between FE's SOL and those of its neighboring entities, known and forecasted regional and interregional transfers shall be included in the derivation of SOL and IRL.
- b. **Extreme Contingencies.** Identify high risk contingencies that are beyond normal studied criteria and determine the performance of the system for these contingencies. Where these extreme contingencies result in cascading outages, determine means to reduce their probability of occurrence or impact. These contingencies and mitigation plans must be communicated to FE operators, ECAR, MISO, and neighboring systems.
- c. **Maximum Import Capability.** Determine the maximum import capability into the Cleveland-Akron area for the summer of 2004, consistent with the criteria stated in (1) above and all applicable NERC and ECAR criteria. The maximum import capability shall take into account historical and forecasted transactions and outage conditions expected with due regard to maintaining adequate operating and local dynamic reactive reserves.
- d. **Vegetation Management.** FE was found to not be complying with its own procedures for right-of-way maintenance and was not adequately resolving inspection and forced outage reports indicating persistent problems with vegetation contacts prior to August 14, 2003. FE shall complete rights-of-way trimming for all 345 kV and 138 kV transmission lines, so as to be in compliance with the National Electrical Safety Code criteria for safe clearances for overhead conductors, other applicable federal, state and local laws, and FE's right-of-way maintenance procedures. Priority should be placed on completing work for all 345 kV lines as soon as possible. FE will report monthly progress to NERC and ECAR.

- e. **Line Ratings.** FE shall reevaluate its criteria for calculating line ratings, survey the 345 kV and 138 kV rights-of-way by visual inspection to ensure line ratings are appropriate for the clearances observed, and calculate updated ratings for each line. FE shall ensure that system operators, MISO, ECAR, NERC (MMWG), and neighboring systems are informed of and able to use the updated line ratings.

### 3. Emergency Response Capabilities and Preparedness

- a. **Emergency Response Resources.** FE shall develop a capability no later than June 30, 2004 to reduce load in the Cleveland-Akron area by 1,500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1,500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be reduced to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies and if approved by ECAR and NERC.
- b. **Emergency Response Plan.** FE shall develop emergency response plans, including plans to deploy the load reduction capabilities noted above. The plan shall include criteria for declaring an emergency and various states of emergency. The plan shall include detailed description of authorities, operating procedures, and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have ability move generation or shed load upon orders from FE operators. The plan shall include procedures for load restoration after the declaration that the FE system is no longer in the emergency operating state.

### 4. Operating Center and Training

- a. **Operator Communications.** FE shall develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center shall allow focus on reliable system operation and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.
- b. **Reliability Monitoring Tools.** FE shall ensure its state estimation and real-time contingency analysis functions are being used to reliably execute full contingency analysis automatically every ten minutes, or on demand, and to alarm operators of potential first contingency violations.
- c. **System Visualization Tools.** FE shall provide its operating personnel with the capability to visualize the status of the power system from an overview

perspective and to determine critical system failures or unsafe conditions quickly without multiple-step searches for failures. A dynamic map board or equivalent capability is encouraged.

- d. **Backup Functions and Center.** FE shall develop and prepare to implement a plan for the loss of its system operating center or any portion of its critical operating functions. FE shall comport with the criteria of the NERC Reference Document – Back Up Control Centers, and ensure that FE is able to continue meeting all NERC and ECAR criteria in the event the operating center becomes unavailable. Consideration should be given to using capabilities at MISO or neighboring systems as a backup capability, at least for summer 2004 until alternative backup functionality can be provided.
- e. **GE XA21 System Updates.** Until the current energy management system is replaced, FE shall incorporate all fixes for the GE XA21 system known to be necessary to assure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.
- f. **Operator Training.** Prior to June 30, 2004 FE shall meet the operator training requirements detailed in NERC Recommendation 6.
- g. **Technical Support.** FE shall develop and implement a written procedure describing the interactions between control center technical support personnel and system operators. The procedure shall address notification of loss of critical functionality and testing procedures.

## **B. Corrective Actions to Be Completed by MISO**

MISO shall complete the following corrective actions no later than June 30, 2004.

- 1. Reliability Tools.** MISO shall fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO shall provide backup capability for all functions critical to reliability.
- 2. Visualization Tools.** MISO shall provide its operating personnel tools to quickly visualize system status and failures of key lines, generators or equipment. The visualization shall include a high level voltage profile of the systems at least within the MISO footprint.
- 3. Training.** Prior to June 30, 2004 MISO shall meet the operator training criteria stated in NERC Recommendation 6.
- 4. Communications.** MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.
- 5. Operating Agreements.** MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

### **C. Corrective Actions to Be Completed by PJM**

PJM shall complete the following corrective actions no later than June 30, 2004.

- 1. Communications.** PJM shall reevaluate and improve its communications protocols and procedures between PJM and its neighboring reliability coordinators and control areas.